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3 Power System Operation Assumptions

This section describes the assumptions pertaining to the US electric power system contained in the EPA Base Case 2000.

3.1 Model Regions

The EPA Base Case 2000 models the electric power sector in the contiguous 48 states and the District of Columbia. Alaska and Hawaii are not included. EPA Base Case 2000 uses 26 model regions to characterize the US power markets. Region definitions are based on power market fundamentals, regional environmental regulations, and operating constraints such as transmission bottlenecks. An attempt is made to model, as much as possible, the actual operation of the US power system. Model regions in EPA Base Case 2000 in general are North American Electric Reliability Council (NERC) regions or subregions and represent aggregations of contiguous control areas. No intra-regional transmission bottlenecks are assumed within the model regions. NERC regions with significant transmission bottlenecks have been disaggregated into multiple modeling regions. Table 3.1 displays a more detailed definition of the 26 model regions in the U.S. EPA Base Case 2000, as well as their corresponding NERC regions.

The previous version of the EPA base case (known as "EPA 1998 Winter Base Case") had 21 model regions. Increasing the number of model regions in EPA Base Case 2000 from 21 to 26 had three primary goals: (1) to better capture the power markets in the West by breaking the NERC WSCC region into a number of subregions; (2) to capture the unique power market in New York City by disaggregating the power market in New York State into four separate model regions (NYC, UPNY, DSNY, and LILC); and (3) to represent Entergy as a separate modeling region to reflect the move of Entergy from the SPP NERC region to the SERC NERC region. Figure 3.1 shows the modeling regions in EPA Base Case 2000.

Figure 3.1: U.S. EPA Base Case 2000 Model Regions

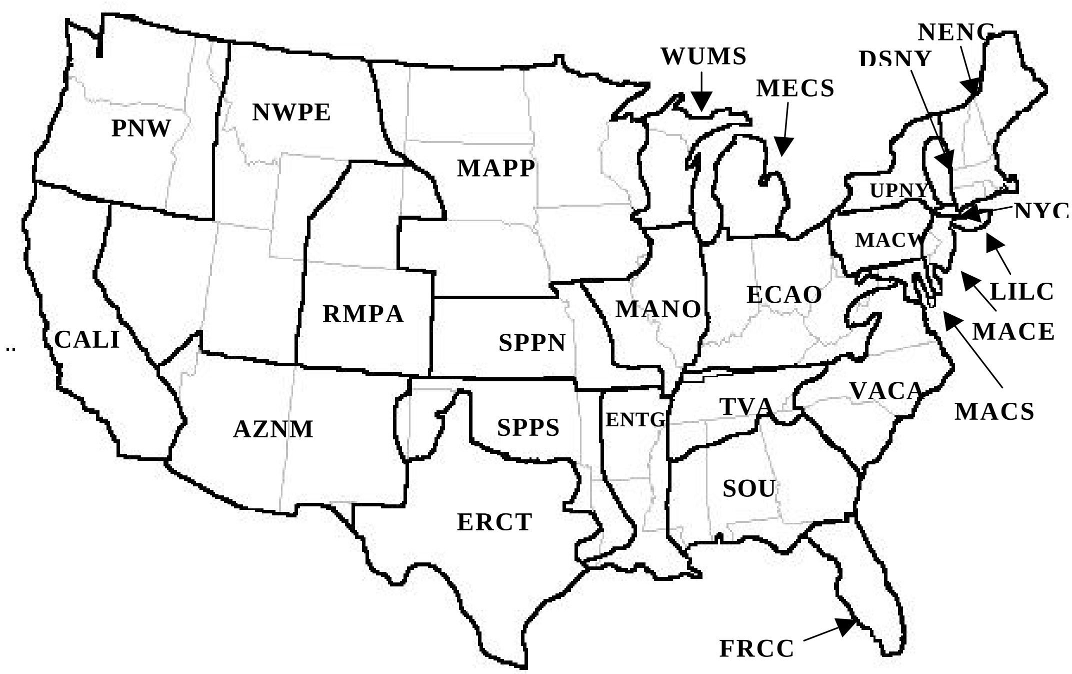

Table 3.1. Mapping of NERC Regions with EPA Base Case 2000 Model Regions

NERC Region	Model Region	Region Description or Reliability Council Name
ECAR	MECS	Michigan Electric Coordination System
ECAR	ECAO	East Central Area Reliability Coordination Agreement - South
ERCOT	ERCT	Electric Reliability Council of Texas
MAAC	MACE	Mid-Atlantic Area Council - East
MAAC	MACW	Mid-Atlantic Area Council - West
MAAC	MACS	Mid-Atlantic Area Council - South
MAIN	WUMS	Wisconsin-Upper Michigan
MAIN	MANO	Mid-America Interconnected Network – South
MAPP	MAPP	Mid-continent Area Power Pool
NPCC	UPNY	Upstate New York
NPCC	DSNY	Downstate New York
NPCC	NYC	New York City
NPCC	LILC	Long Island Lighting Company
NPCC	NENG	New England Power Pool
FRCC	FRCC	Florida Reliability Coordinating Council
SERC	VACA	Virginia –Carolinas
SERC	TVA	Tennessee Valley Authority
SERC	SOU	Southern Company
SERC	ENTG	Entergy
SPP	SPPN	Southwest Power Pool - North
SPP	SPPS	Southwest Power Pool – South
WSCC	CALI	Western Systems Coordinating Council – California
WSCC	PNW	Western Systems Coordinating Council - Pacific Northwest
WSCC	AZNM	Western Systems Coordinating Council - AZNMSNV
WSCC	RMPA	Western Systems Coordinating Council - Rocky Mountain Power Area
WSCC	NWPE	Western Systems Coordinating Council - Northwest Power Pool East

3.2 Electric Load Modeling

Net energy for load and net internal demand are inputs to IPM that collectively represent the grid-demand for electricity. Net energy for load is the projected annual electric grid-demand, prior to accounting for intra-regional transmission and distribution losses. Net internal demand (peak demand) is the maximum hourly demand within a given year after removing interruptible demand. (EPA Base Case 2000 assumptions for net internal demand are discussed below in Section 3.2.4.) Table 3.2 shows the electric demand assumptions (expressed as net energy for load) used in EPA Base Case 2000. For purposes of documentation, the table below describes the national net energy for load. However, the EPA Base Case 2000 uses regional breakdowns of net energy for load for modeling. The regional net energy for load is derived from the national net energy for load based on the regional demand distribution in NERC electric demand forecasts. Model regions that represent subregions of a NERC region are apportioned their net energy for load based on the regional load shapes, which are developed by aggregating load for control areas within each model region.

Table 3.2. Electric Load Assumptions in EPA Base Case 2000[1]

Year	EPA Base Case 2000 Net Energy for Load
	(Billions of kWh)
2005	3,925
2010	4,120
2015	4,366
2020	4,574

3.2.1 Electric Load Growth

The electricity sales forecast in the U.S. Energy Information Administration's *Annual Energy Outlook 2001 with Projections to 2020* (AEO 2001) provided the starting point for the electric load growth assumptions used in the EPA Base Case 2000. AEO2001 projects electricity consumption to grow at an annual rate of 1.8 percent in the period 2000 through 2020. As described below in section 3.2.2, to obtain the values shown in Table 3.2, calculations were performed to fully account for the documented and projected reductions in consumption due to a series of voluntary programs operated by both the U.S. Department of Energy and EPA, collectively known as the Climate Change Action Plan, or CCAP. Factoring these reductions into the AEO2001 projection resulted in an annual growth rate in electricity sales for 2000-2020 of 1.25% . This electricity sales projection was then translated into net energy for load for use in IPM by multiplying the electricity sales by the ratio of net energy for load to total sales as found in AEO2001. The resulting average annual growth rate in net energy for load between 2000 and 2020 in the U.S. EPA Base Case 2000 is 1.2 percent.

3.2.2 CCAP Reductions

CCAP programs, like EPA's Energy Star and DOE's Motor Challenge Programs, reduced electricity consumption by approximately 97.5 billion kWh in year 2000 and are projected to result in additional savings of 277 billion kWh in year 2010 and 495 billion kWh in year 2020 beyond the AEO2001 projections of electricity sales. (See Appendix A 3.I for a fuller discussion of methodology used to derive the CCAP projections and electric demand forecast for the EPA Base Case 2000.) The values shown in Table 3.2 were obtained using the 2010 and 2020 CCAP projections and linear interpolation for intervening years.

3.2.3 Demand Elasticity

The EPA Base Case 2000 does not incorporate the impact of the price of power on power demand.

3.2.4 Net Internal Demand (Peak Demand)

Net internal demand (peak demand) is the maximum capacity that is needed to meet hourly demand within a given year after removing interruptible demand. In the EPA Base Case 2000, the net internal demand is defined regionally and is based on NERC electric forecasts. Table 3.3 below summarizes the national non-coincidental net internal demand used in the EPA Base Case 2000. The values in Table 3.3 are said to be "non-coincidental," since they represent the sum of each region's net internal (peak) demand which need not occur in the same hour across all regions.

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[1]For specific runs built upon IPM Base Case 2000, the total national net energy for load resulting from the run may differ slightly from the assumptions shown in Table 3.2 due to the exports of electricity, imports, and computational rounding.

Table 3.3. National Non-Coincidental Net Internal Demand

Year	Net Internal Demand (GW)
2005	719
2010	761
2015	812
2020	857

3.2.5 Regional Load Shape

In EPA Base Case 2000, the regional load shape curves contain chronological hourly electric demand. These curves are defined by year and for each model region. Regional load curves used in the EPA Base Case 2000 were developed by aggregating individual utility load curves taken from Federal Energy Regulatory Commission Form 714 data. 1994 was found to be the most recent weather normal year[2] for the NERC regions ECAR and MAIN; 1995 was selected for the NERC regions MAAC, MAPP, NPCC and WSCC; 1996 was selected for the NERC regions ERCOT and SPP; and 1997 was selected for the NERC regions FRCC and SERC.

3.3 Transmission

The United States can be broken down into several power markets that are interconnected by a transmission grid. As discussed earlier, EPA Base Case 2000 characterizes the US into 26 different power market regions. The EPA Base Case 2000 includes explicit assumptions regarding the transmission grid connecting the modeled 26 power markets. This section details the assumptions about the transfer capabilities, wheeling costs and inter-regional transmission used in EPA Base Case 2000.

3.3.1 Inter-regional Transmission Capability

The capability of a transmission link in IPM defines the maximum one-directional flow of power on that link. Table 3.4 below summarizes the inter-regional transmission capabilities assumed in the EPA Base Case 2000.

[2]The term “weather normal year” refers to a representative year whose weather is closest to the long-term (e.g., 1950-85) average weather. The selection of a “weather normal year” can be made, for example, by comparing the cumulative annual heating degreee days (HDDs) and cooling degree days (CDDs) in a candidate year to the long-term average. For any individual day, heating degree days indicate how far the average temperature fell below 65 degrees F; cooling degree days indicate how far the temperature averaged above 65 degrees F. Cumulative annual heating and cooling degree days are the sum of all the HDDs and CDDs, respectively, in a given year.

Table 3.4. Transmission Capabilities between Model Regions

From	To	MW
MECS	ECAO	2250
ECAO	MECS	2250
	MACW	2957
	MANO	1655
	TVA	1890
	VACA	2334
ERCT	SPPS	635
MACE	MACW	1500
	DSNY	1130
MACS	MACW	1800
	VACA	3075
MACW	ECAO	2612
	MACE	3368
	MACS	3075
	UPNY	481
MANO	ECAO	3033
	WUMS	608
	MAPP	531
	SPPN	1191
	TVA	2207
	ENTG	1245
WUMS	MANO	1080
	MAPP	676
MAPP	MANO	1150
	WUMS	324
	SPPN	1172
	ENTG	1000
	NWPE	150
	RMPA	233
NENG	DSNY	1425
UPNY	MACW	1418
	DSNY	3750
DSNY	LILC	788
	MACE	308
	NENG	1125
	UPNY	3750
	NYC	3750
NYC	LILC	788
	DSNY	3750
LILC	DSNY	938
	NYC	788
SPPN	MANO	1228
	MAPP	891
	SPPS	525
	ENTG	636
SPPS	ERCT	569
	ENTG	636
	SPPN	900
	AZNM	315
	ENTG	1200
ENTG	SOU	1136
	TVA	1278
	MANO	1399
	SPPS	292
	SPPN	292
	MAPP	856
SOU	FRCC	4516
	TVA	1810
	VACA	1346
	ENTG	1902
FRCC	SOU	21
TVA	ECAO	2235
	MANO	2331
	SOU	2052
	ENTG	2153
	VACA	2261
VACA	ECAO	2822
	MACS	2794
	SOU	3042
	TVA	2240
CALI	PNW	4922
	AZNM	0
	NWPE	1184
PNW	CALI	5903
	NWPE	1050
RMPA	MAPP	233
	AZNM	518
	NWPE	413
NWPE	RMPA	413
	CALI	1574
	MAPP	113
	AZNM	840
	PNW	2145
AZNM	CALI	5663
	NWPE	638
	RMPA	518
	SPPS	315

[1]See Table 3.1 for an explanation of the model region abbreviations.

The starting point for the transmission link capabilities shown in Table 3.4 was the NERC estimates of First Contingency Total Transfer Capability (FCTTC) for transmission links between regions. FCTTC is the total amount of electric power (net of normal base power transfer[3] plus First Contingency Incremental Transfer Capability (FCITC)[4]) that can be transferred between two areas of the interconnected transmission systems in a reliable manner. Utilities and NERC reliability councils develop estimates of FCTTC and NERC presents the consolidated inter-regional FCTTC data in its summer and winter assessments.

Rather than FCTTC, "sustainable" transmission capability that takes into account simultaneity is a better assumption for modeling transmission capability. For EPA Base Case 2000 the NERC "sustainable" inter-

[3] The normal base power transfer is calculated by summing all of the base power transactions that occur between two regions; this sum represents an outflow from the region that is the net exporter.

[4] The FCITC is defined as the amount of electricity, incremental above normal base electricity transfers that can be transferred over the transmission network in a reliable manner based on the following conditions:

a. With all transmission facilities in service, all facility loadings are within normal ratings and all voltages are within normal limits.
b. The bulk electric system is capable of absorbing the dynamic electric swings and remaining stable following a disturbance resulting in the loss of any single generating units, transmission circuit, or transformer.
c. After the dynamic swings following a disturbance (resulting in the loss of any single generating unit, transmission circuit, or transformer), but before operator-directed system adjustments are made, all transmission facility loadings are within emergency ratings and all voltages within emergence limits.

regional transfer capacity estimates were developed by multiplying the average of Winter 1999/2000 and Summer 2000 FCTTC by a factor that is intended to represent the sustainable transfer capability. Based on previous consultations with NERC staff members and in keeping with the EPA 1998 Winter Base Case, ICF used a factor of 75 percent as an estimate of the long-term, sustainable inter-regional transfer capability. The derating of transmission capability from total transfer capability to "sustainable" transmission capability is necessary for several reasons:

First, the FCITC numbers are calculated on a "non-simultaneous" basis. In other words, an assumption is made that this one-way inter-regional transmission transaction is the only one possible. Thus, if other transfers occur at the same time at their unique maximum potential, it is unlikely that the system will continue to have the capability to meet reliability standards.

Second, FCITC represents emergency transfer capability that is designed to be utilized in case of an emergency disturbance. This "excess" capacity exists for a specific purpose. If this capability is utilized instead for more base power transfers, the ability of the inter-regional system to respond in an emergency can be reduced even beyond the impact of the incremental base power transfer additions.

Third, as NERC discusses in its Reliability Assessments, FCITC does not represent a fixed value. It is based upon many different factors that can cause the transfer capability to change, such as generation dispatch, customer demand levels, voltage profiles, availability of equipment, and ambient temperatures. Conditions as studied may not exist at the time of need, and therefore, the indicated transfer capabilities may not be fully available.

3.3.2 Transmission Link Wheeling Charge

Transmission wheeling charge is the cost of transferring electric power from one region to another using the transmission link. The EPA Base Case 2000 assumes a wheeling charge of two mills per kWh. This wheeling charge is applied to electricity transmission between IPM model regions that fall within different NERC regions. However, it is not applied to transmission between model regions that are subregions of the same NERC region.

3.3.3 Transmission Losses

The EPA Base Case 2000 assumes a two percent inter-regional transmission loss of energy transferred. This assumption is consistent with EIA's Annual Energy Outlook (AEO) 2000 report. Since IPM models the wholesale, not the retail electric market, the EPA Base Case 2000 does not include assumptions about distribution losses, i.e., the loss of energy in the retail distribution of electricity.

3.4 International Imports

The US electric power system is connected with transmission grids in Canada and Mexico and the three countries actively trade in electricity. Since the EPA Base Case 2000 does not explicitly include any power markets outside the US, international electric trading between US, Canada and Mexico is represented by an assumption of net imports. Table 3.5 below summarizes the assumption on net imports into the US from Canada and Mexico.

Table 3.5. International Imports Assumptions

	2005	2010	2015	2020
Net International Imports (billion kWh)	49	32	33	27

Source: Based on AEO 2000

3.5 Capacity, Generation and Dispatch

While the capacity of existing units is exogenous to IPM, generation and dispatch are endogenous decisions in IPM. Existing capacity in EPA Base Case 2000 was developed in the National Electrical Energy Data System (NEEDS 2000), a database which provides IPM with data on all currently operating and planned-committed units. NEEDS 2000 is discussed in full in section 4.1.

A unit's generation over a period of time is defined by its dispatch pattern over that duration of time. IPM determines the optimal economic dispatch profile given the operating and physical constraints imposed on the unit. In EPA Base Case 2000 unit specific operating and physical constraints are generally captured through availability and turndown constraints. However, for some unit types, capacity factors are used to capture the resource or other physical constraints on generation. The two cases are discussed in more detail in the following two sections

3.5.1 Availability

Power plant "availability" is the percentage of time that a generating unit is available to provide electricity to the grid. Availability takes into account both scheduled maintenance and forced outages; it is formally defined as the ratio of a unit's available hours adjusted for derating of capacity (due to partial outages) to the total number of hours in a year when the unit was in an active state. For most types of units in IPM, availability parameters are used to specify an upper bound on generation to meet demand. Table 3.6 summarizes the availability assumptions used in EPA Base Case 2000. They are based on data from North American Electric Reliability Council's Generating Availability Data System (NERC GADS) and AEO 2000.

Table 3.6. Availability Assumptions in the EPA Base Case 2000

Unit Type	Availability (%)
Biomass	87.7
Coal Steam	85.0
Combined Cycle	90.4
Combustion Turbine	92.3
Gas/Oil Steam	85.0
Geothermal	87.0
IGCC	87.7
Pumped Storage	81.4

Unit types not contained in Table 3.6 above are discussed in section 3.5.2 below.

In the EPA Base Case 2000, separate seasonal (summer and winter) availabilities are defined. For the unit types shown in Table 3.6, summer and winter availabilities differ only in that no planned maintenance is assumed to be conducted during the on-peak summer (June, July and August) months. Characterizing the seasonal variations of hydro, solar, and wind technologies is more complicated due to the seasonal and locational variations of the resources on which they rely. The seasonal variations of hydro are presented in section 3.5.2 and of wind and solar in section 4.4.3.

3.5.2 Capacity Factor

Generation from certain types of units is constrained by resource limitations. These technologies include hydro, wind, and solar. For such technologies, IPM uses capacity factors or generation profiles, not availabilities, to define the upper bound on the generation obtainable from the unit. The capacity factor is the percentage of the maximum possible power generated by the unit. For example, a photovoltaic solar unit would have a capacity factor of 27% if the usable sunlight were only available that percent of the time. For such units, explicit capacity factors or generation profiles mimic the resource availability. The seasonal capacity factor assumptions for hydro facilities were derived from EIA Form 759 data. They are the same as those used in the EPA Winter 1998 Base Case and are presented below in Table 3.7. A discussion of capacity factors and generation profiles for wind and solar technologies is contained in Section 4.4.3 and Appendix 4.2.

Table 3.7. Seasonal Hydro Capacity Factors (%) in the EPA Base Case 2000

IPM Region	Winter Capacity Factor (%)	Summer Capacity Factor (%)	Annual Capacity Factor (%)
AZNM	27.5%	38.7%	32.2%
CALI	29.1%	42.5%	34.7%
DSNY	55.0%	50.8%	53.2%
ECAO	32.0%	28.7%	30.6%
ENTG	37.8%	38.4%	38.1%
ERCT	23.8%	27.9%	25.5%
FRCC	34.5%	22.2%	29.3%
LILC	N/A	N/A	N/A
MACE	88.3%	92.3%	90.0%
MACS	46.6%	24.5%	37.3%
MACW	45.8%	26.5%	37.7%
MANO	58.6%	56.2%	57.6%
MAPP	33.2%	38.9%	35.6%
MECS	76.9%	68.0%	73.2%
NENG	33.3%	22.8%	28.9%
NWPE	27.5%	38.7%	32.2%
NYC	N/A	N/A	N/A
PNW	29.2%	30.5%	29.7%
RMPA	27.5%	38.7%	32.2%
SOU	36.5%	22.3%	30.5%
SPPN	35.5%	34.2%	35.0%
SPPS	37.8%	38.4%	38.1%
TVA	57.3%	43.3%	51.4%
UPNY	55.0%	50.8%	53.2%
VACA	33.3%	22.5%	28.8%
WUMS	55.9%	52.0%	54.3%
National Weighted Average	**33.8%**	**34.8%**	**34.2%**

Capacity factors are also used to define the upper bound on generation obtainable from nuclear units. This rests on the assumption that nuclear units will either run at full capacity or not at all, and, consequently, capacity factors and availabilities are equivalent. The capacity factors (and, consequently, the availabilities) of existing nuclear units in EPA Base Case 2000 vary from region to region and over time. Further discussion of the nuclear capacity factor assumptions in EPA Base Case 2000 is contained in Section 4.5.

3.5.3 Turndown

Turndown assumptions in EPA Base Case 2000 are used to prevent coal and oil/gas steam units from operating strictly as peaking units, which would be inconsistent with their operating capabilities. Specifically, the turndown constraints in EPA Base Case 2000 require coal steam units to generate no less than 54 kWh of electricity in the lower four segments of the load duration curve for every 100 kWh of electricity generated in the top (peak) segment of the LDC. Oil/gas steam units are required to generate no less than 25 kWh of electricity in the lower four segments of the LDC for every 100 kWh of electricity generated in the top segment of the LDC. These turndown constraints were developed by ICF Consulting, Inc. through detailed assessments of the historical experience and operating characteristics of the existing fleet of coal steam and oil/gas steam units. For example, in deriving the turndown factor for coal steam units, ICF considered the number of coal pulverizers per unit as one indicator of the extent that units could respond to changing load.

3.6 Reserve Margins

A reserve margin is a measure of the system's generating capability above the amount required to meet the net internal demand (peak load) requirement. It is defined as the difference between total dependable capacity and annual system peak load divided by annual system peak load. It is expressed in percent. That is,

$$Reserve\ Margin = \frac{Dependable\ Capacity - System\ Peak\ Load}{System\ Peak\ Load} \times 100\%$$

In practice, each NERC region has a reserve margin requirement, or comparable reliability standard, which is designed to encourage electric suppliers in the region to build beyond their peak requirements to ensure the reliability of the electric generation system within the region.

In IPM reserve margins are used to depict the reliability standards that are in effect in each NERC region. Individual reserve margins for each NERC region are derived either directly or indirectly from NERC's electric reliability reports. They are based on reliability standards such as loss of load expectation (LOLE), which is defined as the expected number of days in a specified period in which the daily peak load will exceed the available capacity. The reserve margin assumptions used in EPA Base Case 2000 are presented in Table 3.8 below.

Table 3.8. Planning Reserve Margins in EPA Base Case 2000

Region Description	Reserve Margin
Michigan Electric Coordination System	15.0%
East Central Area Reliability Coordination Agreement - South	15.0%
Electric Reliability Council of Texas	15.0%
Mid-Atlantic Area Council - East	19.0%
Mid-Atlantic Area Council - West	19.0%
Mid-Atlantic Area Council - South	19.0%
Wisconsin-Upper Michigan	17.0%
Mid-America Interconnected Network - South	17.0%
Mid-Continent Area Power Pool	15.0%
Upstate New York	18.0%
Downstate New York	18.0%
New York City	18.0%
Long Island Lighting Company	18.0%
New England Power Pool	18.0%
Florida Reliability Coordinating Council	15.0%
Virginia-Carolinas	12.4%
Tennessee Valley Authority	12.4%
Southern Company	12.4%
Entergy	12.4%
Southwest Power Pool - North	13.6%
Southwest Power Pool - South	13.6%
Western Systems Coordinating Council - California	9.5%
Western Systems Coordinating Council - Pacific Northwest	8.5%
Western Systems Coordinating Council - AZNMSNV	12.9%
Western Systems Coordinating Council - Rocky Mountain Power Area	10.8%
Western Systems Coordinating Council - Northwest Power Pool East	8.5%

3.7 Power Plant Lifetimes

Except for existing nuclear units, the EPA Base Case 2000 does not include any pre-specified assumptions about power plant lifetimes. To accommodate the absence of pre-specified plant lifetimes, all conventional fossil units (i.e., coal, oil/gas steam, combustion turbines, and combined cycle units) are provided with retirement options which allow units to retire due to economic factors. Other non-nuclear units are not provided an economic retirement option, either because they represent such a small portion of the generating population (renewables, fuel cells, landfills, and waste plants) or because an up-front assessment indicated that economics would not cause retirement (hydro and pumped storage).

Lifetimes (corresponding to their Nuclear Regulatory Commission re-licensing deadlines) are pre-specified for nuclear units, but nuclear units are also given lifetime extension options at age 30 and 40. In addition to the scheduled retirement option, nuclear units, like conventional fossil units, are provided with the option to retire early due to economic factors. Nuclear specific assumptions are discussed in detail in Section 4.3.2.

3.8 Heat Rate

Heat rates describe the efficiency of a unit and in EPA's National Electrical Energy Data System (NEEDS) are expressed as BTUs per KWh. As with the 1998 version of NEEDS (NEEDS 1998), the 2000 version of NEEDS (NEEDS 2000) assumes that heat rates of existing units will remain constant over time. This assumption reflects two offsetting factors: (1) plant efficiencies tend to degrade over time and (2) increased maintenance and component replacement work to maintain or improve plant efficiency.

The 1995 EIA Annual Electric Generation Report (EIA 860) was the primary data source for heat rates of existing electric generation units. More recent versions of EIA 860 withhold data on heat rates due to confidentiality rules. NEEDS 1998 contained the heat rate data from 1995 EIA 860.[5] In NEEDS 2000, heat rates for existing units were not changed. Units added to NEEDS during the 2000 updates received default heat rates used in 1998 version of NEEDS. For existing cogeneration units, heat rates represent net heat rates, i.e., heat rates chargeable to electricity generation.

3.9 Existing Environmental Regulation

Assumptions on existing environmental regulations in the EPA Base Case 2000 reflect federal and state implementation of the Clean Air Act Amendments of 1990 (CAAA). These environmental regulatory assumptions affect emissions for SO_2 and NO_x. The regulations are implemented in IPM through system-wide emission and unit-level constraints.

3.9.1 SO_2 Regulations

The broadest system-wide environmental regulation modeled in the EPA Base Case 2000 is the SO_2 allowance trading program established under Title IV of the CAAA. The program, which became fully operational in year 2000, affects all SO_2 emitting electric generating units greater than 25 MWs. The modeled program provides trading and banking of allowances over time across all affected electric generation sources. The annual SO_2 caps over the 2005-2020 modeling horizon reflect the provisions in Title IV. Since the EPA Base Case 2000 uses year 2005 as the first analysis year, a projection of allowance banking behavior through the end of 2004 was needed and is based on ICF's internal forecast. Table 3.9 below summarizes the total annual allowances in the Title IV SO_2 trading program along with the starting bank in 2005 as included in the EPA Base Case 2000.

Table 3.9. Title IV SO_2 Allowance Assumptions

Starting Bank in 2005	3.69 million tons
Annual Allowances: 2005 - 2009	9.47 million tons
Annual Allowances: 2010 -	8.95 million tons

EPA Base Case 2000 also reflects unit-level SO_2 regulation arising out of Federal Implementation Plans (FIP), State Implementation Plans (SIP) or CAAA requirements. The unit-level regulatory SO_2 emission rates in EPA Base Case 2000 represent upper limits on the allowable emission rates. Units are allowed to choose the most economical approach to meet their regulatory emission limits. For example, they might switch to lower sulfur fuel. Alternatively, they might switch to higher sulfur fuel and install pollution control equipment. Since SO_2 emissions are dependent on the sulfur content of the fuel used, the regulatory SO_2 emission rates in EPA Base Case 2000 are used in IPM to define fuel capabilities. For instance, a unit with a regulatory SO_2 emission rate of three lbs/mmBtu would be provided only with those fuel choices and SO_2 emission control options that would allow the unit to

[5] "Analyzing Electric Power Generation under the CAAA," Office of Air and Radiation, US EPA, March 1998.

achieve an out-of-stack rate of three lbs/mmBtu or less. If the unit finds it economical, it may elect to burn a fuel that would achieve a lower SO_2 rate than its specified regulatory emission limit. In EPA Base Case 2000 there are 5 different sulfur grades of bituminous coal, 3 different grades of subbituminous coal, 3 different grades of lignite, and 3 different sulfur grades of residual fuel oil. There are 3 different SO_2 scrubber options for coal units. Further discussion of fuel types and sulfur content is contained in section 8.1.2. Further discussion of SO_2 control technologies is contained in section 5.1.

The unit-level regulatory SO_2 emission rates in NEEDS 1998 were retained in EPA Base Case 2000.[6] SO_2 rates for new units added during the 2000 update to NEEDS were developed from the following hierarchy of data sources:

1. 1998 EIA form 767: All steam units reporting under EIA 767 report their most stringent SO_2 rates (based on federal, state or local regulation). SO_2 rates were developed using Table "BAIR" in EIA form 767.

2. Units with missing or not meaningful data in 1998 EIA form 767 were separated into two groups: units that came online before 1971 and units that came online in or after 1971. For units that came online before 1971, default SO_2 rates were developed from average existing rates based on state and plant type. Table 3.10 summarizes the default SO_2 rates used in EPA Base Case 2000 for such units. Under the Clean Air Act, units that came online in or after 1971 must maintain an SO_2 rate of 1.2 lbs/mmbtu or lower. In accordance with this provision, units that came online in or after 1971 and had no reported SO_2 rates were given a default SO_2 emission rate of 1.2 lbs/mmbtu.

[6] For further details see, "Analyzing Electric Power Generation under the CAAA," Office of Air and Radiation, US EPA, March 1998, page A4-2.

Table 3.10. Default SO_2 Rates (lbs/mmbtu) by State for Coal-Fired Units

State Name	Default SO_2 Rate
Alabama	1.786
Arizona	0.477
Arkansas	0.630
California	0.090
Colorado	0.644
Connecticut	0.494
Delaware	1.405
Florida	1.361
Georgia	1.510
Illinois	1.894
Indiana	1.808
Iowa	2.128
Kansas	0.784
Kentucky	1.517
Louisiana	1.004
Maryland	1.915
Massachusetts	1.556
Michigan	1.108
Minnesota	0.855
Mississippi	1.591
Missouri	1.966
Montana	0.600
Nebraska	0.761
Nevada	0.345
New Hampshire	1.928
New Jersey	1.421
New Mexico	0.447
New York	1.985
North Carolina	1.548
North Dakota	0.998
Ohio	2.995
Oklahoma	0.689
Oregon	0.741
Pennsylvania	1.716
South Carolina	1.392
South Dakota	1.449
Tennessee	2.796
Texas	0.737
Utah	0.527
Virginia	1.230
Washington	1.205
West Virginia	1.773
Wisconsin	1.384
Wyoming	0.408

3.9.2 NO_x Regulations

Much like SO_2 regulations, existing NO_x regulations are represented in EPA Base Case 2000 through a combination of system-level and unit-level NO_x limits. Modeled NO_x regulations in EPA Base Case 2000 include the NO_x SIP Call trading program, Title IV unit specific rate limits, Reasonable Available Control Technology (RACT) on units in ozone non-attainment or in the Ozone Transport Region (OTR)[7] and state specific regulations in Missouri, Texas and Connecticut.

The system-level NO_x program represented in the base case is the NO_x SIP Call. This trading program affects all fossil units in 19 northeastern states. Table 3.11 below highlights the affected states and their respective annual seasonal budgets.

Table 3.11. NO_x SIP Call States and Budget

State	Budget (Tons)
AL	29,022
CT	2,652
DC	207
DE	5,250
IL	32,372
IN	47,731
KY	36,503
MA	15,146
MD	14,656
MI	32,228
NC	31,821
NJ	10,250
NY	31,036
OH	48,990
PA	47,469
RI	997
SC	16,772
TN	25,814
VA	17,187
WV	26,859
Total	**472,961**

The NO_x SIP Call trading program is only in effect during the ozone season (May – September). Since the program allows for trading across units in different states, the total annual NO_x SIP Call budget of 472.96 thousands tons, rather than state-specific budgets, is used.

Unit-level emission limits are captured in the specific NO_x emission rates assigned to each unit represented in the base case. Unlike SO_2 emission rates, NO_x rates are assumed not to vary with fuel, but are dependent on the combustion properties in the generating unit. Under the EPA Base Case 2000, the NOx emission rate of a unit can only change if the unit is retrofitted with NO_x pollution control equipment or repowered.

[7] The Ozone Transport Region consists of the following states: Maine, New Hampshire, Vermont, Massachusetts, Rhode Island, Connecticut, New York, New Jersey, Pennsylvania, Delaware, Maryland, District of Columbia, and northern Virginia.

Unit specific baseline NO_x emission rates used in EPA Base Case 2000 reflect limits specified in Title IV of the CAAA and RACT in ozone non-attainment areas and the OTR region. The NO_x emissions rates also include the assumption that some units will use emissions averaging in order to satisfy the rate limit requirements of Title IV. EPA Base Case 2000 retains the NO_x rates in the NEEDS 1998 database, which was initially developed for the EPA Winter 1998 Base Case. Further details on the algorithms used for the development of these baseline NO_x emissions rates can be found in the documentation for the EPA Winter 1998 Base Case.[8]

Additional baseline NO_x emission rates were developed only for units that were not part of NEEDS 1998. For these units, the following rules were used:

1. For coal steam units, having known firing and bottom types and meeting the specified size requirements, Title IV Phase II NO_x limits were provided as the baseline NO_x emission rates for the units. Table 3.12 summarizes Title IV Phase II NO_x limits.

Table 3.12. Title IV NO_x Emission Limits for Coal-Fired Electric Generation Boilers (lbs/mmbtu)

Boiler Type	MW Size Cutoff	Phase II Limit
Group 1 - Wall-Fired Dry-Bottom	> 25	0.46
Group 1 - Tangential	> 25	0.40
Group 2 - Cell Burners	> 25	0.68
Group 2 - Cyclone	> 155	0.86
Group 2 - Wet-Bottom	> 65	0.84
Group 2 - Vertical	> 25	0.80

2. For coal steam units with no data on firing or bottom types and for other non-coal NO_x emitting units, default NO_x emissions rate were provided in the following manner. If available, the average NO_x emission rate by state and unit type was used. If the average NO_x emission rate was not available for a specific state and unit type combination, the average NO_x emission rate in the model region for that unit type was used as the default NO_x emission rate.

3. Biomass units were given default NO_x rates of 0.02 lbs/mmbtu and landfill gas units were given a default NO_x rate of 0.246 lbs/mmBtu, consistent with the NOx rate assumptions for a new biomass and landfill gas units[9].

[8] "Analyzing Electric Power Generation under the CAAA," Office of Air and Radiation, US EPA, March 1998, page A4-4.

[9] The biomass NO_x rate was based on data from "BIOPOWER: Biomass and Waste-Fired Power Plant Performance and Cost Model, Version 1.0," Electric Power Research Institute, May 1996, while the NOx rate for landfill gas units was based on AP2-47, Office of Air Quality Planning & Standards, US EPA, 1997.

3.9.3 New Source Review (NSR)

EPA Base Case 2000 does not reflect any reductions in utility emissions based on future compliance with the New Source Review (NSR) provisions of the CAA. However, settlements and agreements to come into compliance with the NSR program were included in the base case if they were publicly announced by December 1, 2000, the deadline set for finalizing model assumptions for internal analytical purposes. These included a settlement with Tampa Electric Company (TECO), announced on February 29, 2000, and an agreement in principle with Virginia Electric and Power Company. As part of these agreements specific generating units were required to install pollution control equipment, repower or shut down. Subsequently announced settlements and agreements (e.g., an agreement in principle with Cinergy Corporation, announced on December 21, 2000, and a settlement with PSEG, announced on January 24, 2002), and any changes to the previously announced agreements are not reflected in the base case.

3.9.4 State-Specific Environmental Regulations

EPA Base Case 2000 also includes assumptions on anticipated state-specific environmental regulations in Missouri, Connecticut and Texas. These state-specific regulations affect SO_2 and/or NO_x. In some instances, there is a difference between the modeled regulation and the actual regulation. These modifications were made in order to fit the actual regulation within the modeling framework and do not meaningfully change the nature of the regulation.The details of the assumptions are presented in the Tables 3.13, 3.14,and 3.15 below.

<u>Missouri</u>

Table 3.13. Anticipated Environmental Regulation in the EPA Base Case 2000 for Missouri

Pollutant	**Program Specifications NO_x**	**EPA Base Case 2000 Assumptions NO_x**
Effective Date/Coverage	2003 / Ozone Season	2003 / Ozone Season
Program Levels	• 0.25 lbs/mmBtu in Fine Grid • 0.35 lbs/mmBtu in Coarse Grid	• No distinction between Coarse/Fine Grid • State-wide cap of 43,950 tons
Mechanism	• Cap and Trade • No Banking • 1.5 Trading ratio when coarse grid allowances retired in Fine Grid	• Cap and Trade • No Banking • Affects all fossil units > 25 MW

Note: For purposes of EPA Base Case 2000, the “fine grid” includes the City of St. Louis and the counties of Bollinger, Butler, Cap Girardeau, Carter, Clark, Crawford, Dent, Dunklin, Franklin, Gasconade, Iron, Jefferson, Lewis, Lincoln, Madison, Marion, Mississippi, Montgomery, New Madrid, Oregon, Pemiscot, Perry, Phelps, Pike, Ralls, Reynolds, Ripley, St. Charles, St. Francois, St. Louis, Ste. Genevieve, Scott, Shannon, Stoddard, Warren, Washington, and Wayne. All other counties in Missouri are included in the “coarse grid” portion.

Connecticut

Table 3.14. Anticipated Environmental Regulation in the EPA Base Case 2000 for Connecticut

Pollutant	Program Specifications NO_x	EPA Base Case 2000 Assumptions NO_x	Program Specifications SO_2	EPA Base Case 2000 Assumptions SO_2
Effective Date/Coverage	2006 / Annual	2008 / Annual	2005 / Annual	2005 / Annual
Program Levels	0.15 lbs/mmBtu	• 0.15 lbs/mmBtu • Rate limit on all model plants • Affects all fossil units	50% reduction beyond Title IV	• State-wide cap of 32,530 tons • Affects all fossil units > 25 MW
Mechanism	Plant-wide averaging		• Requires the retirement of an SO_2 allowance for every ton emitted in addition to what is required under Title IV • No Banking	• Cap and trade • Did not subtract allowances under Title IV • No Banking

Texas

In Texas there are three separate regulations, affecting Houston, Dallas/Fort Worth and East and Central Texas. Although these three programs have been modeled separately in EPA Base Case 2000, no attempt has been made to capture the potential intra-regional transmission implications within ERCOT (which primarily contains Texas and is treated as a unique region in EPA Base Case 2000). As a result of the increased environmental compliance cost arising from this program, the EPA Base Case 2000 includes the assumption that no new fossil unit will be located in Houston, Dallas/Forth Worth and East and Central Texas.

Table 3.15. Anticipated Environmental Regulation in the EPA Base Case 2000 for Texas

Texas - Houston

Pollutant	Program Specifications NO_x	EPA Base Case 2000 Assumptions NO_x
Effective Date / Coverage	2005 - 2007 / Annual	2005 / Annual
Program Levels	• 0.01 - 0.03 lbs/mmBtu • Affects both coal and gas units	• Regional cap of 4,710 tons • Affects all fossil units
Mechanism	Plant-specific caps	• Cap and trade • No Banking

Texas - Dallas/Fort Worth

Pollutant	Program Specifications NO_x	EPA Base Case 2000 Assumptions NO_x
Effective Date / Coverage	2003 - 2005 / Annual	2005 / Annual
Program Levels	• 0.01 - 0.03 lbs/mmbtu • 0.033 - 0.06 lbs/mmbtu • Affects both coal and gas units	• Regional cap of 2,160 tons • Affects all fossil units
Mechanism	Plant-specific caps	• Cap and trade • No Banking

Texas - East & Central

Pollutant	Program Specifications NO_x	EPA Base Case 2000 Assumptions NO_x
Effective Date / Coverage	2003 - 2005 / Annual	2005 / Annual
Program Levels	• 0.14 - 0.165 lbs/mmbtu • Affects both coal and gas unit	• Regional cap of 123,530 tons • Affects all fossil units
Mechanism	Plant-specific caps	• Cap and trade • No Banking

3.9.5 Environmental Regulations on New Units

In contrast to the existing and planned/committed units discussed in previous sections, whose emission rates vary from location to location based on the regulations that are in place, there are no location-specific variations in the emission and removal rate capabilities of potential new units. In IPM, potential new units are modeled as additional capacity and generation that may come online in each model region. Across all model regions the emission and removal rate capabilities of potential new units are the same. The only exception is the assumption that, in light of very stringent state emission limits placed on other fossil fired units, no new coal units can be built in the California (CALI) model region. The specific assumptions regarding the emission and removal rates of potential new units in EPA Base Case 2000 are presented in Table 3.16. Except for the NO_x emission rates for conventional pulverized coal (0.05 lb/mmBtu) and combined cycle and IGCC (0.02 lb/mmBtu) units and the mercury removal rates (95%) for conventional pulverized coal and IGCC units, these assumptions coincide with those in AEO 2000. For additional details on the modeling of potential new units see section 4.4.

Table 3.16. IPM Base Case Emissions Assumptions for Potential (New) Units[1]

Gas	Controls, Removal, and Emissions Rates	Conventioal Pulverized Coal	Integrated Gasification Combined Cycle	Combined Cycle	Advanced Combustion Turbine	Combustion Turbine	Biomass Integrated Gasification Combined Cycle	Geothermal	Landfill Gas
SO_2	Removal/Emissions Rate	95% from sulfur content of coal	100%	None	None	None	0.08 lbs/mmBtu	None	100%
NO_x	Emission Rate	0.05 lb/mmBtu	0.02 lb/mmBtu	0.02 lb/mmBtu	0.10 lb/mmBtu	0.10 lb/mmBtu	0.02 lb/mmBtu	None	0.246 lb/mmBtu
CO_2	Emission Rate[2]	205.3 – 215.4 lb/mmBtu2	205.3 – 215.4 lb/mmBtu	117.08 lb/mmBtu	117.08 lb/mmBtu	None	No net emissions		
Hg	Removal Rate[3]	95%	95%	None	None	None	None	None	None
	Emission Rate	Varies with Hg content of Coal	Varies with Hg content of Coal	0.00014 lbs/TBTu	0.00014 lbs/TBTu	0.00014 lbs/TBTu	0.57 lbs/TBtu	8 lbs/TBtu	0 lbs/TBtu

Notes

1. All emissions are assumed to be zero for nuclear, advanced nuclear, wind, fuel cells, solar photovoltaic, and solar thermal.

2. The range of CO_2 emission rates shown in Table 3.16 for conventional pulverized coal and integrated gasification combined cycle units is due to the range of coal types usable in these units. Bituminous, subbituminous, and lignite coals (with CO_2 emission rate: of 205.3, 212.7 and 215.4 lb/mmBtu respectively) can be used as fuel sources in conventional pulverized coal units and as the feedstock for syngas in IGCCs.

3. Although mercury is unregulated under EPA Base Case 2000, mercury reductions are shown for conventional pulverized coal and IGCC units. The mercury removal rate for new conventional pulverized coal units results from the presence of both SCR for NO_X control and a scrubber for SO_2 control. In combination, these two non-mercury controls result in 95% mercury removal. The 95% mercury removal rate shown for IGCCs assumes that once the coal is converted to syngas, 2-stage activated carbon beds are used for mercury removal.

Appendix 3.1 Electric Demand Projections for EPA Base Case 2000

Establishing an Electricity Baseline Projection for EPA Base Case 2000

A Technical Memorandum Prepared by John A. "Skip" Laitner, Senior Economist for Technology Policy, EPA Office of Atmospheric Programs

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The purpose of this memo is to document the development of a baseline electricity scenario over the period 2000 through 2020 for use in the IPM model. To generate the final estimate, I relied on a number of resources including the *Annual Energy Outlook 2001*, various personal communications, and unpublished data from within OAP.

Based on this collection of data and information, a reasonable and defensible projection is shown in Table A3.1 appended at the end of this memo. The methodology used to estimate the reference case forecast together with the supporting information follows.

Since most energy analysts benchmark their reference case to the EIA projections based on the National Energy Modeling System (NEMS), I similarly calibrated my initial baseline to EIA. In this case, I started with the Annual Energy Outlook 2001 with Projections to 2020 (EIA, 2000). As shown in Table A3.1, AEO2001 shows electricity consumption with an annual growth rate of 1.8 percent in the period 2000 through 2020. Other relevant projections are shown in Table A3.1 for comparison.

One important issue is to ensure that electricity consumption projections properly reflect the voluntary programs operated by both the Department of Energy and EPA, collectively known as the Climate Change Action Plan, or CCAP (see, CAR 1997 for more details on the scope and projected impact of these programs). For example, the various Energy Star programs operated by EPA's Climate Protection Partnership Division achieved an estimated electricity savings of 51 billion kilowatt-hours in 1999 [CPPD, 2000]. This is about 1.5 percent of total electricity sales for that year. Collectively, CCAP is anticipated to reduce electricity consumption by about 97.5 billion kWh in the year 2000.

While more and more analysts are beginning to reflect the impact of voluntary programs in their writings (see, for example, DeCanio, 1998; and Horowitz, et al, 2000), it is less clear that EIA and other forecasts reflect the full impact of voluntary programs into their projections. For example, a phone conversation with DRI indicated that while that macroeconomic forecast reflects anticipated growth and technological change, voluntary programs were not specifically included in their current forecasts (Rhodes, 2001).

At the same time, however, EIA does attempt to capture at least part of the influence of voluntary programs on electricity consumption (Wade, 2000). Examination of the data underlying the AEO2001 forecast indicated that perhaps 30 percent of the voluntary program impacts reflected in CAR 1997 are captured in the AEO2001. In other words, of the projected savings of 97.5 billion kWh anticipated in CAR 1997, EIA appears to credit the programs with only 27.8 billion kWh. This is about one-half of the program impacts expected from the EPA programs alone. For the years 2010 and 2020, the non-credited program impacts increase to about 277 and 495 billion kWh, respectively (see Table A3.1).

Reflecting the non-credited CCAP programs in the AEO2001 forecast effectively lowers the reference case projections by 6.7% and 10.3% for the years 2010 and 2020, respectively. As shown in Table A3.1, this has the effect of lowering the overall growth rate from 1.8% to 1.25% in the period 2000 through 2020.

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Table A3.1. Key Data for Recommendation on EPA Base Case 2000 Baseline Electricity Forecast

	2000	2005	2010	2015	2020	AAGR
GDP AEO2001 (Billion $1996)	$ 9,338	$ 10,960	$ 12,667	$ 14,635	$ 16,515	2.89%
Electricity Prices AEO2001 ($1999/kWh)	$ 0.068	$ 0.062	$ 0.059	$ 0.059	$ 0.060	-0.62%
Electricity Sales Forecasts (Billion kWh)						
NERC ES&D 2000	3632	4003	4368			1.86%
CERA	3655	4084				2.25%
DRI Macro	3379	3653	3796	4011	4215	1.11%
DRI Energy	3379	3622	3883	4163	4462	1.40%
AEO2001	3364	3761	4147	4484	4804	1.80%
STEO Jan 2001	3398					
EPA Base Case Recommended w/o CCAP	3364	3761	4147	4484	4804	1.80%
EPA Base Case 2000 Recommended w/CCAP	3364	3675	3871	4112	4309	1.25%
DRI w/CCAP	3379	3537	3606	3790	3967	0.81%
AEO 2001 w/CCAP	3364	3675	3871	4112	4309	1.25%
AEO2001 Supply to Demand Ratio	1.072	1.068	1.064	1.062	1.062	
EPA Base Case 2000 Recommended Supply	3606	3925	4120	4366	4574	1.20%
CCAP Savings (Billion kWh)						
Projected Program Impacts	97.5	213.6	468.1	585.8	733.0	10.61%
Net of AEO2001 Estimates	69.7	155.5	346.6	442.5	565.0	11.03%
Calibrated to 2000 Estimates Sales	0.0	85.7	276.8	372.8	495.2	